Decision **PROPOSED DECISION OF COMMISSIONER PICKER**
(Mailed July 10, 2015)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 12-11-005 (Filed November 8, 2012)

DECISION REVISING THE GREENHOUSE GAS EMISSION FACTOR TO DETERMINE ELIGIBILITY TO PARTICIPATE IN THE SELF-GENERATION INCENTIVE PROGRAM PURSUANT TO PUBLIC UTILITIES CODE SECTION 379.6(b)(2) AS AMENDED BY SENATE BILL 861

Table of Contents

Title **Page**

DECISION REVISING THE GREENHOUSE GAS EMISSION FACTOR TO DETERMINE ELIGIBILITY TO PARTICIPATE IN THE SELF-GENERATION INCENTIVE PROGRAM PURSUANT TO PUBLIC UTILITIES CODE SECTION 379.6(b)(2) AS AMENDED BY SENATE BILL 861 1
Summary 2
1. Background 2
2. ~~SGIP~~GHG System Performance Over Time 6
   2.1. ~~SGIP~~GHG Project Performance Degradation ..... ~~6~~7
   2.2. Length of GHG Emissions Comparison Period ..... ~~7~~8
3. The Updated Avoided GHG Emissions Factor for Generation Technologies under § 379.6(b)(2) ..... ~~7~~8
   3.1. Operating Margin or Build Margin Methodology ..... ~~8~~9
      3.1.1. Operating Margin Effect 10
      3.1.2. Build Margin Effect 11
         3.1.2.1. Non-Renewable Generation ~~Technology~~ ..... ~~8~~Technologies 13
         ~~3.1.2.~~3.1.2.2. Renewable Capacity Avoided by ~~SGIP~~GHG Projects ~~12~~1
   3.2. Data Source ~~-~~– Emission Rates for Gas-Fired Generation Facilities ~~14~~18
      3.2.1. Operating Margin Effect ~~-~~– Emission Rates ..... ~~15~~19
      3.2.2. Build Margin Effect ~~-~~– Emission Rates ..... ~~17~~21
      3.2.3. Weighting Load-Following and Peaker Plants in the Final Emission Rate ..... ~~18~~23
   3.3. Line Losses Avoided by ~~SGIP~~GHG Projects ..... ~~20~~25
4. ~~SGIP~~GHG GHG Emissions Eligibility Factor – The Equation ..... ~~22~~26
5. Combined Heat and Power ..... ~~23~~28
   5.1. Boiler Efficiency Factor ..... ~~23~~28
   5.2. Differentiating between On-Site Usage of CHP Generation and Exports to the Grid ..... ~~24~~29
6. Energy Storage ..... ~~25~~30
   6.1. Line Loss Factors ..... ~~28~~33

Table of Contents (cont.)

Title	Page
7. Safety Considerations	~~29~~34
8. Comments on Proposed Decision	~~29~~34
9. Assignment of Proceeding	~~30~~34
Findings of Fact	~~30~~35
Conclusions of Law	~~36~~41
ORDER	~~37~~43

APPENDIX A - Share of Avoided Renewables in Calculating SGIP GHG Emissions Eligibility Threshold
APPENDIX B - SGIP GHG Eligibility Emissions Factors, kgCO2/MWh
APPENDIX C – Calculation of Minimum Round-Trip Efficiency

DECISION REVISING THE GREENHOUSE GAS EMISSION FACTOR TO DETERMINE ELIGIBILITY TO PARTICIPATE IN THE SELF-GENERATION INCENTIVE PROGRAM PURSUANT TO PUBLIC UTILITIES CODE SECTION 379.6(b)(2) AS AMENDED BY SENATE BILL 861

Summary

Pursuant to Public Utilities Code Section 379.6(b)(2),[1] this decision updates the greenhouse gas (GHG) emission factor that determines eligibility to participate in the Self Generation Incentive Program.~~[1]~~ The updated factor explicitly reflects the displaced emissions from existing capacity and the avoided need for new capacity. The emission factor for generation technologies is updated from 379 kilograms carbon dioxide per megawatt hours ($kgCO_2/MWh$) to ~~360 $kgCO_2/MWh$.~~350 $kgCO_2/MWh$, averaged over the first ten years of a project's operations, for applications received in program year 2016. Because Public Utilities Code Section 399.15 imposes increasing renewable energy procurement targets through 2030, the GHG eligibility factor declines for subsequent program years, to 337 $kgCO_2/MWh$ for program year 2020. In addition, the minimum required round-trip efficiency for storage technologies is updated from 63.5~~%~~ to 66.5%, averaged over the first ten years of a project's operations. This proceeding remains open.

1. Background

Senate Bill (SB) 412 (Kehoe, Stats. 2009, ch. 182) extended the Self~~-~~-Generation Incentive Program (SGIP) until January 1, 2016 and directed the California Public Utilities Commission (Commission) to adopt rules that limit eligibility for the program to "distributed energy resources that the commission,

[1] All code references are to the Public Utilities Code unless otherwise indicated.

~~[1] All code references are to the Public Utilities Code unless otherwise indicated.~~

in consultation with the State Air Resources Board (ARB), determines will *achieve reductions of greenhouse gas emissions…*" (*Emphasis added*.) SB 412 is codified at, among other code sections, Public Utilities (Pub. Util.) Code Section 379.6.

On September 8, 2011, the Commission adopted Decision (D.) 11-09-015, which implemented SB 412 and set a greenhouse gas (GHG) emission rate eligibility threshold of 379 kilograms carbon dioxide per megawatt hours (kgCO_2/MWh). As a result, fossil-fuel consuming technologies with GHG emission rates above that threshold were not permitted to receive incentives from the ~~SGIP~~GHG program. In adopting this rule, D.11-09-015 based the 379 ~~kg CO~~kgCO_2/MWh avoided emissions factor, in part, on the factor of 437 ~~kg CO~~kgCO_2/MWh used in ~~California ARBs AB~~the ARB's Assembly Bill (AB) 32 Scoping Plan (2008) to estimate the benefits of avoided grid electricity based on the average emissions of natural gas electricity generation.[2]

In D.11-09-015, the Commission adjusted the ARB's emission factor of 437 kgCO_2/MWh downward by 20% to reflect that utilities' electricity procurement resource mix included roughly 20% of renewable resources, as required under the then-effective Renewable Portfolio Standard (RPS) statute.[3] Additionally, in D.11-09-015, the Commission noted that adjusting the ARB's emissions factor downward to reflect the utilities' 20% statutory RPS procurement directive was ~~likely~~ conservative because the RPS program procurement target had increased by statutory amendment to 33% of retail electricity procurement by the target

[2] ~~Assembly Bill 32 (~~AB 32~~)~~ required the ARB to develop a Scoping Plan to describe the approach California will take to reduce GHG to achieve the goal of reducing emissions to 1990 levels by 2020. The Scoping Plan was first considered by the ARB in 2008. AB 32 required that it be updated every five years. ARB approved the First Update to the Climate Change Scoping Plan on May 22, 2014.

[3] The RPS program is codified in Section 399.11 et seq. These code sections have been ~~revised~~amended since the issuance of D.11-09-015.

date of 2020, which would likely ~~to~~ further reduce the emissions of avoided grid purchases.

In D.11-09-015, the Commission also supported the downward adjustment of the ARB's emissions factor of 437 kgCO_2/MWh because the ARB's figure was based on the weighted average emission rate of natural gas-fired power plants operating from 2002 to 2004 and did not reflect the lower emission rate of newer more modern gas-fired generation units that ~~SGIP~~GHG projects may avoid going forward.[4] The emission factor adopted in D.11-09-015 incorporates a 7.8% average transmission and distribution line loss factor to estimate the GHG emissions of the additional electricity displaced by consuming electricity that is generated on-site.

Regarding energy storage technologies, Energy Division's September 2010 Staff Proposal calculated the minimum round trip efficiency that would be required to avoid GHG emissions and arrived at 67.9%. Staff recommended requiring a minimum round trip efficiency of 70% in order to be conservative. D.11-09-015 approved storage for ~~SGIP~~GHG participation but did not comment on the minimum round trip efficiency requirement. Following the decision, the GHG program administrators filed Advice Letter (AL) PG&E 3253-G/3940-E ~~*et seq.*~~ to revise the ~~SGIP~~GHG Handbook to reflect the changes ordered by the Commission. In the AL, the program administrators proposed requiring a minimum round trip efficiency of 67.9%.

The Energy Division issued a disposition letter approving the AL, ~~but it was appealed by~~and the California Energy Storage Association (CESA) appealed the disposition letter. Addressing that appeal, the Commission issued Resolution E-4519 accepting CESA's proposed 5% differential in line loss factors between

[4] D.11-09-015 at 15.

peak and off-peak, ~~with the effect being that~~decreasing the minimum round trip efficiency needed to qualify for ~~SGIP decreased~~GHG from 67.9~~%~~ to 63.5%.

SB 861 (Budget Act of 2014, Stats. 2014, ch. 35) further extended ~~SGIP~~GHG from January 1, 2016 to January 1, 2021 and added § 379.6(b)(2), a provision requiring the Commission to update the GHG emissions eligibility factor. This subsection provides as follows:

> On or before July 1, 2015, the commission shall update the factor for avoided greenhouse gas (GHG) emissions based on the most recent data available to the State Air Resources Board for GHG emissions from electricity sales in the self-generation incentive program administrators' service areas as well as current estimates of GHG emissions over the useful life of the distributed energy resource, including consideration of the effects of the California Renewables Portfolio Standard.

As part of the Commission's process to update the GHG emissions eligibility factor in compliance with § 379.6(b)(2), the assigned Commissioner in this proceeding issued a ruling on March 27, 2015 requesting parties to comment on ten questions related to the calculation of the GHG emissions avoided by generation and storage technologies.

Parties filed comments between April 14 and 16, 2015.[5] Several parties filed reply comments on April 23, 2015.[6]

[5] Doosan Fuel Cell America (Doosan), the Office of Ratepayer Advocates (ORA), Southern California Gas Company (SoCalGas), National Fuel Cell Research Center (NFCRC), California Clean DG Coalition (CCDGC), FuelCell Energy (FCE), Southern California Edison Company (SCE), California Solar Energy Industries Association (CALSEIA), Center for Sustainable Energy (CSE), Center for Energy Efficiency and Renewable Technologies ~~(CEERT)~~, Bloom Energy, California Cogeneration Council (CCC), EtaGen, SolarCity, San Diego Gas & Electric Company (SDG&E), Cogeneration Association of California, Pacific Gas and Electric Company (PG&E), ~~California Energy Storage Alliance (~~CESA~~)~~, Fuel Cell & Hydrogen Energy Association (FCHEA).

[6] SoCalGas, SCE, EtaGen, CCDGC, CSE, SDG&E, Bloom Energy, PG&E, CESA, and SolarCity.

On October 7, 2015, Governor Brown signed SB 350 (De Leon, Stats. 2015, ch. 457) into law. Among its provisions, SB 350 revises the RPS program by requiring California's retail electricity providers to procure a minimum of 50% renewable energy by 2030. Additionally, it sets interim of targets of 40% by 2024 and 45% by 2027.

2. ~~SGIP~~GHG System Performance Over Time

We first address the performance of the ~~SGIP~~GHG-incentivized systems and the duration of time over which GHG emissions are required to occur. To meet the ~~SGIP~~GHG GHG eligibility requirements, D.11-09-015 found that ~~SGIP~~GHG systems must emit GHGs at a rate less than the adopted GHG emission factor when averaged over a ten -year period and assuming annual performance degradation of 1%. For pure electric fuel cells and for AES systems, this determination is made for specific model types and then applied to all applications with those model types. For Combined Heat Power (CHP), however, because the GHG impact depends on the design of the heat recovery system and on its operation, D.11-09-015 orders that each individual application be reviewed for GHG emissions eligibility compliance.[7]

2.1. ~~SGIP~~GHG Project Performance Degradation

In D.11-09-015 the Commission noted, "Staff's analysis of fossil-fuel based [Distributed Energy Resources] technologies rested on a few key assumptions: 1) the electrical conversion efficiency of all technologies degrades at a rate of 1% per year…."[8] The March 27, 2015 Assigned Commissioner Ruling (ACR) asked for comment on the degradation assumption. Of those parties responding to this question, about half[9] believe that the 1% annual degradation rate assumption is

[7] D.11-09-015 at 16.
[8] D.11-09-015 at 14.
[9] Bloom Energy, CESA, Doosan, PG&E, SolarCity.

adequate and appropriate. Among those who argue otherwise, ~~Fuel Cell Energy~~FCE favors a 2% annual assumption for all projects, or else a different number for each technology type. EtaGen and CSE favor a different number for each technology type, with values to be determined based on historical analysis. CCC argues that well~~-~~-maintained facilities experience no degradation over time and, if anything, offer opportunities for improvements. CCDC believes that actual degradation is lower than 1% and asks the Commission to use manufacturer data to determine more accurate values. ~~SCE~~GHG states that a 2 to 3% degradation rate for energy storage systems is more appropriate.

No party has provided compelling evidence pointing to a different assumed degradation factor, and so we will keep the current assumed degradation rate at 1%.

2.2. Length of GHG Emissions Comparison Period

The March 27, 2015 ACR asked for parties to comment on whether any revisions should be made to the current 10 -year requirement. Most parties supported maintaining the 10 -year rule. However, CCC supported extending the period to 15 years on the basis that natural gas plants will be the avoided resource base through at least 2030. We acknowledge that some ~~SGIP~~GHG-funded systems will likely operate for more years than others, but we refrain from extending the comparison period because we are concerned that a longer period may serve to penalize equipment that is expected to last longer. Furthermore, we favor the administrative simplicity of using the same evaluation period for all technologies.

In theory, the 10-year period of GHG comparison should begin with the year that a project achieves operations. However, basing the comparison period on the year in which a project commences operations would introduce an additional source of uncertainty in the GHG process. For the purposes of administrative simplicity and greater participant certainty, the GHG comparison period, and resulting GHG performance threshold, should be known at the time a participant applies for funds from the GHG. Because it takes some time following the confirmation of an incentive reservation before a project receives permission to operate, we will define the comparison period as consisting of the ten-year period beginning with the year following the program year in which the application is received.

3. The Updated Avoided GHG Emissions Factor for Generation Technologies under § 379.6(b)(2)

To update the avoided GHG emissions eligibility factor for ~~SGIP~~GHG projects, we address three key questions:

> First, do ~~SGIP~~GHG projects: (1) reduce generation output from existing dispatchable generation facilities (the operating margin effect), (2) reduce the need for new generation facilities that would otherwise have been built to serve the load met by the ~~SGIP~~GHG projects (the build margin effect), or (3) produce both an operating margin effect and a build margins effect?
>
> Second, what data or estimates should be used for the GHG emission rates of fossil-fired generation offset by ~~SGIP~~GHG projects?
>
> Third, what line loss percentage should be used to account for the line losses avoided by generating electricity for use on site, which is typical for ~~any SGIP~~GHG eligible projects?
>
> We address these questions below.

3.1. Operating Margin or Build Margin Methodology

The March 27, 2015 ACR asked parties to address the question of whether ~~SGIP~~GHG projects avoid GHG emissions by reducing the output from existing facilities operating on the margin or from the capacity of facilities that would otherwise be built.[10] Parties presented different opinions on this topic. Some expressed clear support for an operating margin approach.[11] Under an operating margin approach, GHG resources would be assumed to offset only the emissions of a generator that operates on the margin at the time the GHG resource operates; GHG technologies would not be assumed to offset any zero-emission resources unless the marginal generator in California happened to be a zero-emission resource. However, GHG, one of the parties supporting an operating margin approach, nevertheless suggests that "cumulative GHG projects do affect long run resources" and recommends emission factors that incorporate the RPS effect.[12] Others express clear support for a build margin approach, although one of these parties, CCC, asserts that GHG projects will not avoid new renewable energy capacity.[13] Because the underlying logic and the analysis of the operating and build margin effects differ fundamentally, we address each of these effects separately.

[10] The ACR referred to this issue as the short-run and long-run effects but noted that it is also known as the operating margin and build margin effects. Since the nomenclature led to some confusion in the comments on the ACR, we consistently use the terms operating margin and build margin in this decision.

[11] These parties are Bloom Energy, CCDGC, Doosan, EtaGen, Fuel Cell Energy, FCHEA, NFCRC, ORA, SoCalGas, and SCE.

[12] SCE April 17, 2015 opening comments at 2 and 8.

[13] CCC, CESA, CalSEIA, PG&E, SDG&E, and Solar City.

3.1.1. ~~Generation Technology~~Operating Margin Effect

Nearly all parties agree that ~~SGIP~~GHG generation projects displace generation from a combination of existing combined cycle gas turbines (CCGTs) and simple cycle combustion turbines (CTs) ~~and that new gas-fired plants will be slightly more efficient than existing plants. However, the choice between the two approaches –~~. There was less agreement regarding the existence of an operating margin ~~or build margin – could have a large impact on the final avoided emission rate if the technologies adopted for new generation differ significantly from the existing fleet of dispatchable resources. Importantly, with few, if any, exceptions the resources built to serve California's electricity load for the foreseeable future will consist of gas-fired and renewable energy facilities. The inclusion of renewable facilities among the portfolio of plants used to set the build margin rate decreases the avoided emissions rate compared to the operating margin.~~ effect on renewable energy sources. Several parties suggested that because renewable energy resources are not dispatchable, the operating margin methodology should not assume any reduction in renewable output. Bloom Energy conceded that some renewable energy may be displaced, but only to the extent that renewable resources must be curtailed to prevent overgeneration. Using modeling estimates produced by E3 and referenced in CESA's opening comments, Bloom Energy proposes that the renewable energy adjustment should, under a 33% RPS scenario, only reduce the operating margin factor by 1.6%, the number of hours of overgeneration in the modeling results.[14] PG&E appears to support a similar approach.[15] Other parties suggest that the operating

[14] Bloom Energy April 23, 2015 reply comments at 7.
[15] PG&E April 17, 2015 opening comments at 5.

margin should incorporate a reduction in renewable energy, weighted in proportion to the RPS obligation.

Existing renewable energy resources are not dispatchable, and thus, do not respond to changes in load. Many of the arguments put forth by parties in favor of including displaced renewable energy in the operating margin either fail to address to this basic aspect of renewable facilities' operations or are based on estimates of future curtailment of renewable energy. We conclude that because renewable energy output is rarely curtailed at present, and estimates of future curtailment rest on projections of a pervasive overgeneration problem in future years, the operating margin should exclude renewable energy resources.

3.1.2. Build Margin Effect

In D.11-09-015, the Commission assumed ~~SGIP~~GHG projects would avoid the need for new generation, meaning that the Commission found that ~~SGIP~~GHG projects affect the build margin and avoid the need for utilities to procure new renewable capacity as well as new fossil-fired capacity. This finding was based, in part, on the fact that the Pub. Util. Code, specifically the statutorily based RPS program, obligates the utilities and other load serving entities to meet their retail loads with a certain percentage of renewable energy. Thus, a reduction in load served should lead to a reduction in the amount of renewable energy a utility must procure to reach or maintain the required share of renewable energy.

To the extent the utilities' sales forecasts account for energy efficiency and self-generation, both of which reduce the utilities' sales, they would need to procure ~~both~~ less renewable energy and less conventional energy than they would in the absence of energy efficiency and self-generated electricity.

~~Parties presented different opinions on this topic. Generally, no position was unanimously endorsed. Some expressed clear support for an operating~~

~~margin approach.[11] Under an operating margin approach, SGIP resources would be assumed to offset only the emissions of a generator that operates on the margin at the time the SGIP resource operates; SGIP technologies would not be assumed to offset any zero-emission resources unless the marginal generator in California happened to be a zero-emission resource. However, SCE, one of the parties supporting an operating margin approach, nevertheless suggests that "cumulative SGIP projects do affect long run resources" and recommends emission factors that incorporate the RPS effect.[12] Others express clear support for a build margin approach, although one of these parties, CCC, asserts that SGIP projects will not avoid new renewable energy capacity.[13]~~

Determining whether ~~SGIP~~GHG and other self-generation projects affect procurement of new ~~renewable~~ capacity hinges in part on whether the utilities' load forecasts, upon which they base their renewable and non-renewable capacity purchase decisions, account for load reductions due to self-generation. ~~The answer is straightforward.~~ As CESA explains in its reply comments, the utilities' load forecasts, as approved in the Long Term Procurement Planning (LTPP) proceeding, are derived from the California Energy Commission's (CEC's) biennial Integrated Energy Policy Report (IEPR) and the ten-year demand forecasts incorporated therein. CESA observes that the CEC's 2014 – 2024 demand forecast specifically cites ~~SGIP~~GHG as one of the "major programs designed to promote self-generation" that are accounted for in the demand forecast.~~[14]~~[16]

Based on this information, we conclude that GHG projects have some impact on the build margin. Because different factors govern utilities' procurement of new renewable and non-renewable capacity, we discuss the build margin impact of renewable and non-renewable generation technologies separately.

~~[11] These parties are Bloom Energy, CCDGC, Doosan, EtaGen, Fuel Cell Energy, FCHEA, NFCRC, ORA, SoCalGas, and SCE.~~

~~[12] SCE April 17, 2015 opening comments at 2 and 8.~~

~~[13] CCC, CESA, CalSEIA, PG&E, SDG&E, and Solar City.~~

~~[14] CESA reply comments at 3, *citing to California Energy Demand 2014 – 2024 Final Forecast. Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand and Energy Efficiency* at 38–39.~~

3.1.2.1. Non-Renewable Generation Technologies

In light of the CEC's accounting for ~~SGIP~~GHG in the demand forecast, ~~SGIP~~GHG, in conjunction with the utilities' other demand-side programs, likely ~~have~~has some impact on the procurement of energy capacity. However, it is difficult to ascertain at what point self-generation and other demand-side measures affect the decision to procure new capacity. The utilities procure new non-renewable capacity in order to maintain grid reliability. As explained in the World Resources Institute's GHG reduction guidelines document (World Resources Institute's GHG Guidelines) cited in the ACR, during periods of overcapacity, projects may only displace the operating margin for some period of time before they affect the build margin.~~[15]~~[17]

In the most recent Commission LTPP decision authorizing procurement of new capacity, the Commission found that new capacity would not be needed in either the ~~SCE~~GHG or SDG&E territories before 2022.~~[16]~~[18] Due to the lack of near-term need for new capacity at the system and local levels and the fact that procurement decisions for new capacity are generally made several years in advance of new capacity coming online, we find it reasonable to assume that ~~SGIP~~GHG projects will primarily avoid the need for generation from existing resources in the near-term.

However, over the longer-term, we assume that ~~SGIP~~GHG projects will offset the need for new capacity. Determining the timing of the avoidance of new capacity would necessitate analysis of factors specific to the locations and generation profiles of each project. In order to account for both types of avoided

~~15~~17 Broekhoff, D., 2007. *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects.* World Resources Institute. (*See* Box 8.3.) http://www.wri.org/sites/default/files/pdf/ghgprotocol-electricity.pdf.

~~16~~18 D.14-03-004 at 2.

generation effects while balancing the need for an acceptable level of administrative complexity, we adopt a methodology that assigns equal weight to the short-term and long-term effects over a ten-year time span. In effect, this assumes that GHG projects have an operating margin effect during the first five years of operations, and a build margin effect thereafter. This assumption is consistent with the finding in D.14-03-004 that new capacity may be needed by 2022, which approximately equals five-years following the timeframe that projects applying for GHG funds in program year 2016 would be expected to achieve commercial operations. However, if a future LTPP decision find a need for additional gas-fired capacity within a time frame that is significantly nearer or further than five years from the current year, this assumption may need to be revised.

3.1.2.2. ~~3.1.2.~~ Renewable Capacity Avoided by ~~SGIP~~GHG Projects

Having found above, that ~~SGIP~~GHG projects are likely to have some long-term effect on new gas-fired capacity, we now address the question of whether ~~SGIP~~GHG projects avoid the need for renewable capacity in addition to gas-fired capacity.

The methodology adopted in D.11-09-015 and incorporated into the ~~SGIP~~GHG Handbook assumes ~~SGIP~~GHG projects displace renewable energy generation in proportion to the statutorily-mandated amount of RPS procurement required at the time. As described earlier, this method implicitly assumes a build margin effect from the first year of operations.

~~SCE~~GHG, CESA, CALSEIA, and SolarCity support the continued application of an avoided renewable capacity assumption. ~~SCE~~GHG, which supports an assumption of a predominately short-term grid impact, nevertheless argues that the ~~SGIP~~GHG eligibility should start with the GHG emission rates of gas-fired power plants from the CEC's Quarterly Fuel and Energy Report (also referred to as QFER) data, reduced by the required RPS percentage for each of the first five years of the project's operations.[~~17~~19] CALSEIA and SolarCity support assuming that ~~SGIP~~GHG projects displace 40% renewables given the Governor's goal of meeting half of the state's projected electricity load with renewable energy procurement by 2030.

SoCalGas, EtaGen, CCDC, and CCC take the position that AB 327 eliminated the connection between customer measures and wholesale renewables by creating the 2020 target of 33% as a floor instead of a ceiling. Therefore, they claim that no assumptions can be made based on renewable procurement targets.[~~18~~20]

While AB 327 permits the Commission to require utilities to procure more than the minimum amounts prescribed by the RPS statute, the Commission has not exercised that authority. Moreover, the parties making this argument fail to explain why this would fundamentally change the interaction between the renewable energy requirements and the build margin. As long as any future renewable energy requirements are based on a percentage of retail sales, the rationale underlying D.11-09-015 still applies: the utilities would forecast their loads, taking into account ~~SGIP~~GHG and other demand -side measures, and submit compliance plans demonstrating sufficient procurement of renewable capacity to meet the higher standard set by the Commission.

[~~17~~19] SCE April 17, 2015 opening comments at 8.

[~~18~~20] EtaGen April 17, 2015 opening comments at 4–5. EtaGen states that "With this change in law, it is not possible for SGIP projects to displace renewable capacity procurement since utilities are now free to procure renewable capacity that generates energy in amounts greater than the RPS floor."

~~Therefore, we find it reasonable to adopt a methodology that assumes 33% avoided renewable capacity for the long-term share of the GHG emission rate threshold, with an adjustment to reflect line losses. Furthermore, the fact that we, or the Legislature, could increase the RPS requirement in the near future renders a 33% avoided renewable capacity assumption rather conservative. However, until either the legislature codifies a higher RPS or we act on the authority granted by AB 327 and explicitly adopt a higher standard than the RPS minimum, we will not assume a higher avoided renewable capacity than 33%.~~

It is important to note that, unlike non-RPS capacity, RPS compliance obligations generally drive the procurement of energy from new RPS-eligible resources rather than a reliability-driven need for new capacity. Consequently, local or system needs determinations have less bearing on the timing of renewable capacity additions. While it is conceivable that one or more utilities may have no need for system or local capacity for many years, that would not affect the build margin calculation for RPS-eligible resources.

One factor affecting the avoided emissions calculations that has changed since the issuance of the original proposed decision on July 10, 2015 is the signing into law of SB 350 by Governor Brown. The original proposed decision supported a 33% avoided renewable energy assumption, also beginning in the sixth year after an GHG project commences operations. Because this decision will affect the GHG rules beginning with applications submitted for program year 2016, it was reasonable to use a fixed 33% RPS percentage in the avoided emissions calculation formula because the avoidance of renewable generation would be expected to occur no earlier than 2021. Thus, the lower renewable energy requirements in the years leading up to 2020 would not factor into the analysis, and neither the Commission nor the Legislature had established a higher target post-2020.

In light of the 50% renewable target for 2030 created by SB 350, higher RPS requirements for the years after 2020 must be taken into account. In addition to the 50% by 2030 target, SB 350 establishes interim targets of 40% by 2024 and 45%

by 2027. Presumably, as the utilities account for GHG capacity and other demand reduction measures, they will strive to reduce procurement of renewable energy roughly in proportion to each year's obligation. While the interim targets are set by SB 350 for 2024 and 2027, this leaves open the question of the trajectory in the intervening years. For purposes of estimating the avoided GHG emissions due to GHG projects, we will assume that targets for the intervening years will be determined by linear interpolation of the targets defined by statute. This approach is consistent with the Commission's implementation of the 33% RPS requirement in D.11-12-020. In so doing, we emphasize that we do not prejudge the implementation of SB 350 in Rulemaking (R.) 11-05-005 or its successor. Should a subsequent decision establish RPS targets for intervening years using a different approach, the GHG avoided GHG estimation methodology should be revised accordingly.

We find ~~a line loss adjustment reasonable~~that the RPS percentages should be adjusted for line losses because~~, while~~ the RPS program requires utilities to procure a certain percentage of renewable energy as a share of their *retail* sales, and no adjustment is made for the line losses that occur to deliver energy to customers. As a result, a given RPS target results in a lower percentage of renewable energy as a share of the wholesale energy procured to serve customers. For example, attaining a 33% RPS target on a grid with 10% line losses results in a 29.7% (33% * (1-10%)) share of renewable energy at the wholesale level. Therefore, the build margin calculation should account for the smaller share of renewable energy actually displaced at the wholesale level.

Appendix A lists the assumed RPS targets for each year through 2030, the RPS targets corrected for line losses, and the applicable five-year weighted averages for GHG program years 2016 through 2020.

We note that another provision of SB 350 may affect how avoided emissions should be calculated in the future. In addition to increasing utilities', and other load-serving entities', RPS requirements, SB 350 added § 454.52 to the Pub Util. Code, which requires load-serving entities to file integrated resource plans with the Commission. In the course of implementing the § 454.52 requirements, the Commission may determine that another approach to estimating avoided emissions more appropriately reflects the utilities' planning assumptions and methodologies under an integrated resource planning framework.

3.2. Data Source – Emission Rates for Gas-Fired Generation Facilities

We next address the issue of what data should be used for determining the GHG emission rate of gas-fired generation facilities. As noted in the March 27, 2015 ACR, § 379.6(b)(2) directs the Commission to update the GHG eligibility factor "based on the most recent data available to the State ARB for GHG emissions from electricity sales in the self-generation incentive program administrators' service areas."

As several parties indicated, the ARB does not collect data that would help ~~to~~ estimate avoided emissions on either an operating margin or build margin basis. The ARB collects, and reports, total emissions for all stationary facilities emitting 10,000 metric tons of CO_2 equivalent or more per year. However, the ARB neither collects nor reports nameplate capacity or net electricity generated by facility. Furthermore, the ARB does not assign emissions in any way to the utilities' service areas. Therefore, we must rely on other sources of data to calculate marginal emission rates.

3.2.1. Operating Margin Effect ~~-~~– Emission Rates

Because the necessary data is not reported to the ARB, and thus not available for our use, parties recommend using data from the CEC. ~~SCE~~GHG suggests relying on the CEC's Quarterly Fuel and Energy Report, which provides monthly data on power plant rated capacity, generation, fuel type, and fuel consumption. ~~SCE~~GHG suggests that capacity factors can be derived to determine which plants are marginal and fuel consumption and generation data can be used to calculate GHG emission rates for the marginal plants.[~~19~~21]

EtaGen and Doosan also recommended using CEC data but refer to a 2014 CEC draft staff paper (2014 CEC Draft Staff Paper) that analyzed historic QFER data to separately estimate the average heat rates of load-following[~~20~~22] and peaking resources.[~~21~~23] In this 2014 CEC Draft Staff Paper, the CEC staff collected historic data from 2004 through 2013 and extrapolated heat rates out to 2023 using a linear regression. EtaGen calculated an average 10 -year avoided emission value using the values from Table 1 of the 2014 CEC Draft Staff Paper, arriving at a final emission factor of 449 $kgCO_2/MWh$.[~~22~~24] However, this factor incorporates a peaker plant weighting that we find excessive, as discussed below.

[~~19~~21] SCE April 17, 2015 opening comments at 2.

[~~20~~22] Load-following power plants run during the day and early evening. They either shut down or greatly curtail output during the night and early morning, when the demand for electricity is the lowest. The exact hours of operation depend on numerous factors. One of the most important factors for a particular plant is how efficiently it can convert fuel into electricity.

[~~21~~23] California Energy Commission, 2014. *Estimating Fuel Displacement for California Electricity Reductions: Summary of Staff's Proposed Method.* http://www.energy.ca.gov/chp/documents/2014-07-14_workshop/Estimating_Fuel_Displacement_Summary.pdf.

[~~22~~24] EtaGen April 17, 2015 opening comments of at 8–9.

Bloom Energy suggests using data from a 2014 CEC report on the efficiency of gas fired generation (CEC Thermal Efficiency Report).[~~23~~25] This report provides heat rates for California gas-fired generation from 2001 through 2013 based on CEC's QFER data. Bloom Energy favors excluding aging steam~~-~~generation plants, which are run primarily for reliability purposes, and cogeneration plants, which typically do not respond to changes in load.[~~24~~26] Table 2 of the report shows that 2013 average heat rates are 7,205 and 10,268 Btu/kWh, respectively, for combined cycle and peaker plants.

Several parties recommend reasonable approaches to calculating the avoided GHG emissions from existing power plants. As most parties who took a position on the data sources have agreed, we believe that, at least as an interim measure, data collected by the CEC provide the best data for the purpose of calculating the GHG emissions of marginal power plants in California. We will continue to work with CEC staff and ARB to identify sources of data collected by ARB that may be useful to further refine the avoided emissions estimates. Rather than reinventing the wheel by analyzing raw QFER data, we find that the CEC staff has conducted analysis that is useful to determining the emissions rate of gas-fired resources. While we find the linear regression approach proposed by CEC staff promising, at this time the CEC has not issued a final report and, therefore, we are reluctant to rely on the draft methodology.

We find it reasonable to rely on the 2013 data from the CEC Thermal Efficiency Report, as recommended by Bloom Energy. The heat rate for load-following plants, as cited in the report, was 7,205 Btu/kWh and the heat rate for peaker plants was 10,268 Btu/kWh. Using the United States

[~~23~~25] Nyberg, M. *Thermal Efficiency of Gas-Fired Generation in California: 2014 Update.* California Energy Commission, 2014. CEC-200-2014-005.

[~~24~~26] Bloom Energy April 17, 2015 opening comments at 7–8.

Environmental Protection Agency's standard conversion factor of 53 $kgCO_2$/MMBtu, we find that these heat rates are equivalent to emission rates of 382 $kgCO_2$/MWh and 544 $kgCO_2$/MWh respectively.

3.2.2. Build Margin Effect ~~-~~– Emission Rates

We now address emission rates for peaker and load-following plants in the build margin. Because the conversion efficiencies of these technologies continue to improve, the emission rates of the new gas-fired plants displaced by ~~SGIP~~GHG projects and other demand-side measures will be lower than the existing plants whose output is avoided on the operating margin.

Most parties did not support the finding of a build margin effect. As a result, only a few parties provided information concerning the emission rates of new gas-fired units. SolarCity supports the continued use of 368 $kgCO_2$, adopted in D.11-09-015.~~[25]~~[27] EtaGen suggests that any proposed deviations to the baseload heat rates in the 2014 CEC Draft Staff Paper take into account that only dry cooled combined cycles would ever be permitted in California and that such plants would ~~be~~operate 5-10% less ~~efficient.[26]~~efficiently.[28]

CCC refers to values from the California Independent System Operator (CAISO) on the costs and performance of new generating units in California.~~[27]~~[29] Because the data source cited provides a range of heat rate values for both CCGTs and CTs, CCC proposes taking the mid-point value for each. CCC arrives at recommended values of 393 $kgCO_2$ for CCGTs and 504 $kgCO_2$ for CTs. The value provided for CCGTs is actually slightly higher than the emission rate of the existing fleet using the 2013 CEC data cited by Bloom Energy. Because that value is higher than the performance of the existing fleet, we will continue to the

~~25~~27 SolarCity April 17, 2015 opening comments at 11.
~~26~~28 EtaGen April 17, 2015 opening comments at 4.
~~27~~29 CCC April 17, 2015 opening comments at 7.

use the current value of 368 $kgCO_2$. As EtaGen observed, that value may need to be revisited when we have more operating data on new dry-cooled plants in California.

The value for new CTs proposed by CCC is more than 7% lower than the efficiency of the existing fleet. It is worth noting that the emissions rate of the existing fleet of CTs is lower than the assumed value for a new CT used in the current ~~SGIP~~GHG Handbook, which is 575 $kgCO_2$. This value is now outdated and we will revise it accordingly. The new value proposed by CCC would constitute a substantial reduction in efficiency relative to the existing fleet, and we are not certain that efficiency is plausible under realistic operating conditions.

Therefore, we find that, in the absence of better data, the same efficiency improvement (between the existing plants in the operating margin and the future avoided plants in the build margin) assumption should be applied to CTs that we have adopted for CCGTs – namely, a heat rate reduction of 3.7%. This results in an assumed emissions rate of 524 $kgCO_2$ for new CTs.

3.2.3. Weighting Load-Following and Peaker Plants in the Final Emission Rate

In order to determine a final emission rate under § 379.6(b)(2), the contribution of load-following and peaker plants must be weighted to account for the approximate amount of time spent operating on the margin – which would be the amount of time potentially displaced by ~~SGIP~~GHG projects.

Parties presented a variety of positions. EtaGen generally supported the linear regression approach in the 2014 CEC Draft Staff Paper. EtaGen, however, disagrees with the weighting of load-following and peaking plants. The 2014 CEC Draft Staff Paper suggests that an avoided marginal emission factor should weight peaking resources by the amount of electricity produced as a share of all electricity produced by the facilities deemed to comprise the peaking and load~~-~~-following categories.

EtaGen, Bloom Energy and the CCC recommend that the weighting of peaker plants reflect the time these facilities operate and are thus likely to provide the marginal source of electricity. This approach to weighting peaker and load-following plants is more consistent with the methodology described in the World Resources Institute's GHG Guidelines.[~~28~~30]

EtaGen recommends using the highest capacity factor of any single peaking power plant from the CEC's QFER data, which, according to EtaGen, is 20.6%, the capacity factor of the KRCD Malaga Peaking Plant in 2013. We find that using the highest single capacity factor of any peaking plant in California results in an overly generous estimate of the number of hours peaker plants are likely to be displaced by ~~SGIP~~GHG projects.

In contrast to the approach proposed by EtaGen, Bloom Energy cites the CEC Thermal Efficiency Report, which indicates that the average capacity factor of peaker plants in 2013 was 5.1%. While this approach would be more reasonable than the value suggested by EtaGen, it may underestimate the number of hours that peaker plants spend on the margin because plants that operate for very few hours pull down the average. The average capacity factor of all peaker plants does not necessarily represent the number of hours that peaker plants spend on the margin because more efficient plants should generally operate at higher capacity factors and provide the marginal unit during many hours when less efficient plants are not operating.

[~~28~~30] Broekhoff, D., 2007. *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects.* World Resources Institute. http://www.wri.org/sites/default/files/pdf/ghgprotocol-electricity.pdf.

CCC cites the CAISO's 2013 *Annual Report on Market Issues and Performance*, which indicates that based on the economics of combustion turbine operations, new combustion turbines are estimated to have operated at an approximately 8% capacity factor during the 2010 to 2013 time period. In comments on the proposed decision, Bloom Energy observes that the CAISO has issued an updated 2014 *Annual Report* that cites a 10% peaker capacity factor.[31] We find this estimate to be more representative of the amount of time that peakers are likely to provide the marginal resource because newer, more efficient combustion turbines should operate more often than the average of all peaker plants. Therefore, we adopt ~~8~~10% as the weighting factor to apply to peaker plants in the calculation of marginal emission rates.

3.3. Line Losses Avoided by ~~SGIP~~GHG Projects

The calculation of an avoided GHG emission rate for ~~SGIP~~GHG projects and other demand-side measures must account for the line losses that they save by providing electricity for on-site consumption.~~[29]~~[32] The current methodology uses a consistent statewide assumption of 7.8%, which, like the avoided emission rate for gas-fired generation, was adopted from ARB's 2008 Scoping Plan. As CESA notes, the 7.8% value used by ARB was taken from the CEC's 2007 energy demand forecast for 2008 – 2018.~~[30]~~[33] This number is now several years out of date and should be updated.

[31] Bloom Energy, August 4, 2015 reply comment on the PD at 4.

~~[29]~~[32] In this section we only address the average line losses that will be used for generation projects. On-peak and off-peak line losses for storage projects are discussed in a separation section of this decision.

~~[30]~~[33] CESA April 17, 2015 opening comments at 11-12.

Parties have proposed three different data sources that may be used to update the line loss factor. CESA recommends using a 2011 CEC study on transmission losses. While that study provides a range of values based on 2008 and 2009 data, CESA suggests using 6.2%, which is the midpoint of the range in the CEC study.[~~31~~34] ~~SCE~~GHG cites the same study but states that it provides a value of 7.25% for "overall system losses." ~~SCE~~GHG recommends using utility-specific factors found in the report. Bloom Energy suggests 7.3% from a different CEC report, the 2015 – 2025 demand forecast.[~~32~~35] CCC and EtaGen both cite the same loss factors disaggregated by utility and by the transmission, sub-transmission, and distribution portions of the system.[~~33~~36] [~~34~~37] Their approaches use data from CAISO, PG&E's 2014 ~~GRC~~GHG Phase 2 testimony, ~~SCE~~GHG's 2015 ~~GRC~~ GHG Phase 2 testimony, and a data response from SDG&E in R.14-07-002. The proposed total line loss factor differs slightly because it appears that EtaGen added the separate loss factors together whereas CCC calculates a product of 1 minus each loss factor. Although EtaGen, like CCC, provides a table with loss factors for each utility, EtaGen proposes using one statewide, load-weighted average factor of 8.7%. CCC does not state that utility-specific factors should be used, but presumably that is CCC's intent because it does not provide a statewide average.

[~~31~~34] CESA April 17, 2015 opening comments at 12, *citing* to Wong, Lana, 2011. *A Review of Transmission Losses in Planning Studies*. California Energy Commission at 24. Available at http://www.energy.ca.gov/2011 publications/CEC-200-2011-009/CEC-200-2011-009.pdf.

[~~32~~35] Bloom Energy April 17, 2015 opening comments at 12, *citing* to Kavalec, Chris, 2015. *California Energy Deand Updated Forecase, 2015-2025*. California Energy Commission, CEC-200-2014-009-CMF.

[~~33~~36] CCC April 17, 2015 opening comments at 5.

[~~34~~37] EtaGen April 17, 2015 opening comments at 6.

We find the data provided by CCC and EtaGen persuasive and we will adopt this approach to calculate the line loss factor that partially determines the ~~SGIP~~GHG avoided GHG emission factor. In order to maintain a simpler and more uniform program structure, we prefer to use one statewide average line loss factor and accordingly we adopt the approach described by EtaGen. However, EtaGen errs in adding the individual components together. Using the multiplicative calculation used by CCC, we derive a final line loss factor of 8.4%.

4. ~~SGIP~~GHG GHG Emissions Eligibility Factor – The Equation

Based on the above, we find that to calculate the GHG emissions eligibility factor, it is reasonable to use the following equation:

$$GHG\ EF = (0.5(ER_{OLF} * (1 - WFP) + ER_{OP} * WFP) + 0.5 * (1 - RPS\% * (1 - LLF)) * (ER_{BLF} * (1 - WFP) + ER_{BP} * WFP)) / (1 - LLF)$$

Where:

GHG EF = greenhouse gas emission factor

ER_{OLF} = operating margin emission rate of load-following plants = 382 $kgCO_2/MWh$

WFP = weighting factor for peaker plants = ~~8~~10%

ER_{OP} = operating margin emission rate of peaking plants = 544 $kgCO_2/MWh$

RPS% = average RPS portfolio requirement ~~= 33%~~for the program year (i.e., project years 6 – 10)

ER_{BLF} = build margin emission rate of load-following plants = 368 $kgCO_2/MWh$

ER_{BP} = build margin emission rate of peaking plants = 524 $kgCO_2/MWh$

LLF = line loss factor = 8.4%

Substituting the adopted values for Program Year 2016 into this equation yields:

GHG EF = (0.5 (382 kgCO_2/MWh * (1 ~~–0.08~~– 0.10) + 544 kgCO_2/MWh * ~~0.08~~0.10) + 0.5 (1-~~0.33~~0.40 * (1 – 0.084))) * (368 kgCO_2/MWh * (1 – ~~0.08~~0.10) + 524 kgCO_2/MWh * ~~0.08~~0.10))/(1 – 0.084)

GHG EF = ~~360~~350 kgCO_2/MWh

Therefore, we find that, pursuant to § 379.6(b)(2), to be eligible for ~~SGIP~~GHG incentives, gas-fired technologies must emit GHGs at a rate no higher than this emission factor averaged over the first ten years of operation, and the calculation of a project's emissions must take into account the assumed 1% annual degradation in electrical efficiency~~.~~ for technologies subject to this assumption. This results in a maximum first-year emission rate of 334 kgCO_2/MWh. The ten-year average and first-year factors for program years 2016 – 2020 are listed in Appendix B.

5. Combined Heat and Power

We now address two issues specific to combined heat and power (CHP) projects: (1) whether to update the boiler efficiency factor, and (2) whether to differentiate between on-site consumption of CHP generation and exports to the grid.

5.1. Boiler Efficiency Factor

Regarding the first issue, because ~~SGIP~~GHG CHP projects displace useful thermal output that would have otherwise been provided by boilers, we find that an assumed boiler efficiency is needed to credit CHP project for avoided boiler fuel. Notably, the assumed boiler efficiency factor could significantly impact the eligibility of CHP projects because the higher the assumed boiler efficiency, the fewer GHG emissions avoided by a CHP project.

Most parties recommended continuing to use the current 80% boiler efficiency factor. These parties claimed that existing or "legacy" boilers generally achieve the 80% level of efficiency or less. Only PG&E supported a higher boiler efficiency factor. PG&E recommended that the benchmark for boilers be modified to reflect the efficiency of currently available boilers. PG&E claimed that all new boilers sold in California must comply with a minimum 79 to 80% efficiency but supported a higher assumed efficiency – of 85% – because mid~~-~~-efficiency boilers with efficiencies ranging from 83 to 88% are readily available and rebates are provided for this class of boilers. No party submitted data regarding either the vintage of boilers displaced by ~~SGIP~~GHG-funded CHP projects or the penetration of mid- and high-efficiency boilers sold in California.

Increasing the assumed boiler efficiency might be justified if a large number of ~~SGIP~~GHG-funded CHP projects avoid the need for a *new* boiler and if most of the new boilers installed in recent years in California were more efficient than the minimum levels required by California law. However, we have no data regarding either the vintage of boilers displaced by ~~SGIP~~GHG-funded CHP projects or the penetration of mid- and high-efficiency boilers sold in California.

Accordingly, we find it reasonable to retain the 80% assumed boiler efficiency for ~~SGIP~~GHG CHP projects. We may reconsider this value if parties provide data in the future regarding the extent to which ~~SGIP~~GHG-funded CHP projects displace new boilers and the prevalence of mid- and high-efficiency boilers among recently purchased boilers in the California market.

5.2. Differentiating between On-Site Usage of CHP Generation and Exports to the Grid

The second topic specific to ~~SGIP~~GHG CHP projects raised in the ACR is whether non-Net Energy Metering (NEM) exports from ~~SGIP~~GHG CHP projects should be compared only to fossil-fired plants for purposes of calculating avoided emissions.

Calculating a different rate of avoided emissions based on fossil-fuel or a different resource mix becomes moot if no build margin effect is assumed because the electricity produced by CHP units will only displace electricity from existing, dispatchable plants. Most of the parties commenting on this topic recommended no differentiation based on their opposition to finding that ~~SGIP~~GHG projects have a build margin effect. [~~35~~38] ~~SCE~~GHG supported a methodology with an RPS-interaction effect but suggested against adopting a different emission standard for non-NEM exports because there have been very few non-NEM grid exporting projects and because ~~SGIP~~GHG only allows up to 25% of the energy generated on-site to be exported.[~~36~~39] SoCalGas similarly pointed out the rarity of non-NEM exporting projects and suggested that most non-NEM projects have protection relays to prevent exports.[~~37~~40]

Accordingly, we find it reasonable to refrain from adopting a separate avoided GHG emission rate for non-NEM exports from ~~SGIP~~GHG CHP projects on the basis that no party supports the adoption of a separate avoided GHG emission rate for non-NEM exports from ~~SGIP~~GHG CHP projects and the apparent scarcity of projects that would benefit from a separate rate.

6. Energy Storage

The March 27, 2015 ACR asked if, given the changing nature of energy resources serving California's load, the current assumptions for calculating the avoided GHG emissions for ~~SGIP~~GHG energy storage are still valid. Energy storage systems are typically net *consumers* of electricity. Therefore, unlike other ~~SGIP~~GHG technologies, energy storage systems increase load. However, as

[~~35~~38] *See, e.g.,* April 17, 2015 opening comments of CCC, California Clean DG Coalition, Fuel Cell Energy, and SoCalGas.

[~~36~~39] SCE April 17, 2015 opening comments at 7.

[~~37~~40] SoCalGas April 17, 2015 opening comments at 6–7.

recognized in D.11-09-015 and the current ~~SGIP~~GHG Handbook, storage may reduce GHG emissions by shifting load from hours in which marginal demand is met by less~~-~~-efficient plants.

The current ~~SGIP~~GHG methodology assumes that storage devices charge during off-peak hours and discharge during peak hours. The net emission impact of operating ~~SGIP~~ energy storage systems are estimated using the emission rate of a new CT as a proxy for the emissions avoided by reducing demand during peak hours and the emission rate of a new CCGT plant as proxy for the off-peak marginal emissions rate.

In response to the ACR, PG&E and ~~SCE~~GHG recommended maintaining the current assumption for now but improving the avoided emissions estimate in the future through additional analysis, such as the use of production cost modeling.~~[38]~~[41]

SolarCity stated that its energy storage systems operate in the range of 80~~%~~ to 86% round trip efficiency, but SolarCity recommended a minimum 75% round trip efficiency to not preclude participation by emerging technologies. SolarCity provides no analysis of the GHG impacts of the 75% rate to support its position.~~[39]~~[42]

CESA stated that the assumption that CTs are marginal during peak hours and CCGTs are marginal during off-peak hours is no longer valid. As the percentage of renewable energy in California's supply grows, renewables will increasingly operate as the marginal resource. Citing analysis by CAISO and E3, CESA stated that some negative pricing is already occurring in the CAISO

~~[38]~~[41] SCE April 17, 2015 opening comments at 7; PG&E April 17, 2015 opening comments at 10–11.

~~[39]~~[42] Solar City April 17, 2015 opening comments at 9–10.

markets and CAISO forecasts that renewable curtailment will increase substantially under a 40% RPS.~~[40]~~[43]

CESA recommended using a production cost model rather than relying on broad assumptions regarding the resources incremented and decremented by the dispatch of storage systems. In order to develop an estimate of a ~~roundtrip~~round trip efficiency that will yield GHG savings, CESA retained a consultant, Energy Exemplar, to run the PLEXOS production cost model, which is also used by CAISO.

Energy Exemplar modeled the WECC interconnect using the 40% RPS scenario data from CAISO and found that the addition of 412.5 MW of storage with two hours of capacity and 60% round-trip efficiency reduced annual GHG emissions by nearly 204 thousand tons of CO_2 and reduced renewable curtailment by 8%.~~[41]~~[44] It appears that CESA simply selected the 60% round-trip efficiency value for the PLEXOS model runs rather than attempting to find the minimum round-trip efficiency value that would yield GHG savings.

We find that the production cost modeling approach, as recommended by CESA, is a promising method for determining the GHG emissions eligibility threshold for ~~SGIP~~GHG energy storage as well as generation technologies. Nevertheless, we do not adopt it today because more time is needed to vet the assumptions regarding storage dispatch and other factors influencing the outcome of the PLEXOS results. While parties commented on the increasing likelihood of renewables operating on the margin and associated curtailment, significant curtailment is not expected to occur until renewables reach 40% of the

~~40~~43 CESA April 17, 2015 opening comments at 5–10.
~~41~~44 CESA April 17, 2015 opening comments at 19–20.

portfolio, with most of that curtailment expected from solar.[~~42~~45] ~~Furthermore, as noted previously, the state has not yet officially adopted a 40% or 50% RPS.~~

~~Therefore, we do not find it reasonable to rely on scenarios that assume renewable percentages above 33% by a particular date. However, when~~When more data and operational experience exists to demonstrate that storage avoids solar curtailment, we may revisit the assumption that storage primarily affects the dispatch of CTs and CCGTs. We ~~further find it is reasonable to~~will therefore continue to base ~~SGIP~~GHG GHG eligibility for energy storage systems on the emission rates of CCGTs and CTs. For the emission rate assumptions, we find it reasonable to apply both the operating margin and build margin emission rates for generation technologies and the 50/50 weighting of the two effects as discussed in Section 3.

6.1. Line Loss Factors

The other factor we must address regarding storage eligibility concerns the assumed line loss factors during peak and off-peak hours, which affects the minimum round-trip efficiency. Storage is expected to charge primarily during off-peak hours and discharge during peak hours. Because line losses are substantially lower during off-peak hours and higher during peak hours, lower round-trip efficiencies are required to reduce emissions overall than would be the case if one value for average losses were used instead.

Few parties addressed this issue. SolarCity asked that we retain the 5.3% off-peak and 10.3% on-peak loss factors adopted in Commission Resolution E~~-~~-4519. CESA recommended that the difference between the on-peak and off-peak line loss factors be increased from 5~~%~~ to 10%[~~43~~46] but does not provide

[~~42~~45] CESA April 17, 2015 opening comments at 7.
[~~43~~46] CESA April 17, 2015 opening comments at 17.

specific on-peak and off-peak factors or a basis for calculating the factors that would yield a 10% differential. Therefore, in the absence of adequate information, we find it reasonable to retain the current 5.3% and 10.3% values.

Based on the parameters discussed above for operating margin emission factors, build margin emission factors, line losses, and performance degradation, energy storage projects should achieve a minimum round-trip efficiency of 66.5% over ten years of operations to qualify for ~~SGIP~~GHG, equivalent to a first-year round-trip efficiency of 69.6%. The full calculation is shown in Appendix ~~A~~C.

7. Safety Considerations

We find that the determination of a GHG emission rate pursuant to § 379.6(b)(2) for technologies to be eligible to participate in the ~~SGIP~~GHG raises no safety considerations.

8. Comments on Proposed Decision

The proposed decision of Commissioner Picker in this matter was mailed on ~~____________~~July 10, 2015 to the parties in accordance with § 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were timely filed on ~~_____ by _____,~~July 30, 2015 by Bloom Energy, CCDC, jointly by CESA and NRDC, CSE, EtaGen, NFCRC, PG&E, Sierra Club, jointly by SolarCity and CALSEIA, and TURN and reply comments were timely filed on ~~______ by _______.~~ August 4, 2015 by Bloom Energy, CCDC, jointly by CESA and NRDC, CSE, NFCRC, SDG&E, jointly by SolarCity and CALSEIA, and GHG. The proposed decision has been modified where appropriate in response to the comments and reply comments filed.

9. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Regina DeAngelis and Karin M. Hieta are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. On September 8, 2011, the Commission adopted Decision (D.) 11-09-015, which implemented SB 412 and set a GHG emission rate eligibility threshold of 379 kgCO_2/MWh.

2. The 379 kg CO_2/MWh avoided emissions factor adopted in D.11-09-015 was based on the factor of 437 kg CO_2/MWh used in ARB's 2008 AB 32 Scoping Plan to estimate the benefits of avoided grid electricity.

3. D.11-09-015 adjusted this 437 kgCO_2/MWh factor downward by 20% to reflect the fact that the utilities' electricity resource mix includes renewable resources required under the RPS statute.

4. D.11-09-015 stated that ARB's emissions factor of 437 kgCO_2/MWh was "based on the [weighted average] emission rate of gas-fired power plants from 2002 to 2004, and it does not reflect the lower emission rate of newer gas-fired units that ~~SGIP~~GHG projects may avoid going forward."

5. D.11-09-015 adopted a 7.8% average transmission and distribution line loss factor to account for the electricity and associated emissions saved by serving load with on-site generation.

6. D.11-09-015 adopted a time frame of 10 years for evaluating whether ~~SGIP~~GHG projects reduce GHG emissions and an assumed degradation in electrical conversion efficiency of 1% per year.

7. Storage technologies do not directly emit GHGs; they may cause emissions to occur when they charge and displace emissions when they discharge.

8. In resolution E-4519 the Commission determined that a minimum round-~~-~~trip efficiency for storage technologies of 63.5% was required for a storage device to be GHG reducing.

9. SB 861 extended ~~SGIP~~GHG from January 1, 2016 to January 1, 2021 and added § 379.6(b)(2).

10. Insufficient data was provided to merit changing the assumed 1% per year degradation in conversion efficiency.

11. No party provided compelling reasons to revise the 10 -year time frame for evaluating whether GHG emissions reductions occur.

12. New customer-sited generation may displace emissions from existing dispatchable generation facilities (the operating margin effect), reduce the need for new generation facilities that would otherwise have been built to serve the load met by the ~~SGIP~~GHG projects (the build margin effect), or affect both the operating and build margins.

~~13. California's RPS program requires utilities to procure enough renewable energy to meet a certain percentage of their retail loads with renewable energy by 2020.~~

13. ~~14.~~ The Commission authorizes utilities to procure new capacity for reliability purposes using the CEC's ~~Integrated Energy Policy Report (~~IEPR~~)~~ forecasts as a basis.

14. ~~15.~~ Utilities use the IEPR forecasts as a basis to calculate their renewable net short positions to determine how much renewable energy capacity to procure to comply with the RPS targets.

15. ~~16.~~ The CEC's 2014–2024 demand forecast cites ~~SGIP~~GHG as one of the "major programs designed to promote self-generation" that are accounted for in the demand forecast.

16. ~~17.~~ During periods of overcapacity, projects may only displace the operating margin for some period of time before they affect the build margin.

17. ~~18.~~ In D.14-03-004, , the Commission found that new capacity would not be needed in either the ~~SCE~~GHG or SDG&E territories before 2022.

18. ~~19. The Commission has yet to exercise the authority granted by AB 327 to require the utilities under our jurisdiction to procure more than the minimum 33% prescribed by the RPS statute.~~SB 350 amended § 399.15 of the Pub Util Code to increase the RPS requirement to 50% by the end of the 2028 – 2030 compliance period, with interim targets of 40% by the end of the 2021 – 2024 compliance period and 45% by the end of the 2025 -2027 compliance period.

19. D.11-12-020 established cumulative RPS procurement obligations for each compliance period from 2014 – 2020 using a straight-line trend between the targets set by statute.

20. The RPS program requires load serving entities to procure a certain percentage of renewable energy as a share of their retail loads. Because no adjustment is made for the line losses that occur to deliver energy to customers, a given RPS target results in a lower percentage of renewable energy as a share of the wholesale energy procured to serve customers.

21. ARB collects, and reports, total emissions for all stationary facilities emitting 10,000 metric tons of CO_2 equivalent or more per year. ARB neither collects nor reports nameplate capacity or net electricity generated by facility, nor does ARB assign emissions in any way to the utilities' service areas.

22. The CEC's Quarterly Fuel and Energy Report provides monthly data on power plant rated capacity, generation, fuel type, and fuel consumption.

23. The CEC's *Thermal Efficiency of Gas-Fired Generation in California: 2014 Update* report uses CEC's QFER data to derive heat rates by generation

technology for the years 2001 through 2013. The report shows that 2013 average heat rates are 7,205 and 10,268 Btu/kWh, respectively, for combined cycle and peaker plants, equivalent to emission rates of 382 $kgCO_2$/MWh and 544 $kgCO_2$/MWh, respectively.

24. Because the conversion efficiencies of gas-fired technologies continue to improve, the emission rates of the new gas-fired plants displaced by ~~SGIP~~GHG projects and other demand-side measures will usually be lower than the existing plants whose output is avoided on the operating margin.

25. In California, efficiency improvements of gas-fired technologies may be partially offset if only dry cooled combined cycle plants, which are 5 – 10% less efficient than wet-cooled units, are permitted in the future.

26. The 2013 CAISO *Annual Report on Market Issues and Performance* provides a mid-point estimate of 393 $kgCO_2$ for new CCGTs and 504 $kgCO_2$ for new CTs in California.

27. The value provided for CCGTs in the CAISO report is slightly higher than the emission rate of the existing fleet of CCGTs in 2013 according to the CEC Thermal Efficiency Report.

28. The emissions rate of the existing fleet of CTs, according the CEC Thermal Efficiency Report, is lower than the assumed value of 575 $kgCO_2$ for a new CT used in the current ~~SGIP~~GHG Handbook.

29. World Resources Institute's GHG Guidelines document recommends weighting generation resources in the calculation of marginal emission rates according to the proportion of time that they provide the marginal source of generation.

30. Neither the share of electricity generated nor the average capacity factor of a type of a generation resource provides an accurate estimate of the amount of time that a resource type spends on the margin.

31. The ~~2013~~2014 CAISO *Annual Report on Market Issues and Performance* estimates that new combustion turbines, which should operate more frequently than older less-efficient peaker units, operated at an approximately ~~8~~10% capacity factor during the 2010 to 2013 time period.

32. The calculation of an avoided GHG emission rate for ~~SGIP~~GHG projects and other demand-side measures must account for the line losses that they save by providing electricity for on-site consumption.

33. D.11-09-015 set a single statewide assumption of 7.8% line losses, consistent with ARB's 2008 Scoping Plan and the CEC's 2008 – 2018 demand forecast.

34. The CEC's 2015 – 2025 demand forecast uses an assumed line loss factor of 7.3%.

35. Bottom-up distribution loss data from filings submitted by each utility and transmission loss data derived from CAISO wholesale price data yield a statewide average line loss factor of 8.4%.

36. Because CHP projects displace the useful thermal output that would have otherwise been provided by boilers, an assumed boiler efficiency is needed to credit CHP project for avoided boiler fuel consumption.

37. The assumed boiler efficiency currently in use for ~~SGIP~~GHG is 80%.

38. Electricity exports from CHP systems and other non-NEM sources do not lower retail load and therefore do not displace new renewable generation under the RPS program.

39. An assumed efficiency of 80% is reasonable for the existing fleet of boilers.

40. New mid-efficiency boilers are available with efficiencies ranging from 83~~–~~-88%.

41. No data have been provided in this proceeding regarding the extent to which ~~SGIP~~GHG CHP projects may displace new boilers that would have otherwise been installed rather than existing boilers with several years of useful life remaining.

42. No data have been provided in this proceeding regarding the market penetration of mid- and high-efficiency boilers.

43. Very few non-NEM grid exporting projects have been installed under ~~SGIP~~GHG and many non-NEM projects have protection relays to prevent exports.

44. Energy storage may reduce GHG emissions by shifting load from hours in which marginal demand is met by less-efficient plants, such as simple cycle peaker units, to hours in which highly efficient CCGTs operate on the margin.

45. The current ~~SGIP~~GHG methodology assumes that storage devices charge during off-peak hours and discharge during peak hours. The methodology estimates the net emission impact using the emission rate of a new CT as a proxy for the emissions avoided by reducing demand during peak hours and the emission rate of a new CCGT plant as proxy for the off-peak marginal emissions rate.

46. The operating margin and build margin emission rates for CCGTs and CTs used to determine storage eligibility should be consistent with the emission rates used to determine eligibility for generation technologies.

47. CESA submitted production-cost modeling results demonstrating that storage devices with round-trip efficiencies as low as 60% will reduce GHGs in the WECC territory.

48. Parties did not thoroughly vet CESA's production cost model runs.

49. ~~SGIP~~GHG currently assumes 10.3% line losses during peak hours and 5.3% during off-peak hours.

50. Parties did not provide adequate information to support changing the peak and off-peak line loss factors.

Conclusions of Law

1. The assumption of 1% annual performance degradation for ~~all SGIP~~certain GHG eligible ~~technolgies~~technologies is reasonable and should be maintained.

2. The 10 -year time frame for evaluating whether ~~SGIP~~GHG projects reduce GHG emissions is reasonable and should be maintained.

3. Under the present circumstances on California's grid, it is reasonable to weight the build margin and operating margin effects on a 50/50 basis in the avoided GHG emission factor methodology for ~~SGIP~~GHG projects under § 379.6(b)(2).

4. It is reasonable to set the operating margin emission rate for CCGTs and CTs at 382 $kgCO_2/MWh$ and 544 $kgCO_2/MWh$, respectively.

5. It is reasonable to maintain the build margin emission rate for new CCGTs at 368 $kgCO_2/MWh$.

6. It is reasonable to assume a reduction in the GHG emission rate of new CTs relative to the existing fleet comparable to the 3.7% expected reduction for CCGTs using the operating margin and build margin values adopted for CCGTs.

7. It is reasonable to set the build margin emission rate for CTs at 524 $kgCO_2/MWh$.

8. It is reasonable to set the avoided GHG emissions calculations for ~~SGIP~~GHG projects using a statewide average line loss factor of 8.4%.

9. ~~Assuming that~~The new renewable capacity ~~is~~ avoided in the build margin ~~in proportion to the current 33% RPS requirement is conservative because the Legislature or the Commission may increase the renewable requirement in the future.~~should reflect the increasing RPS procurement obligations the Legislature enacted in SB 350.

10. The share of renewable energy avoided in the build margin effect should be adjusted for line losses to reflect that the RPS obligations are defined relative to total retail load.

11. It is reasonable to assume a 10% weighting of peaker plants in the non-RPS portion of the GHG GHG emission standard calculation.

12. ~~11.~~ It is reasonable to revise the ~~SGIP~~GHG GHG emissions eligibility threshold under § 379.6(b)(2) for generation technologies ~~to 360 kgCO_2/MWh.~~applying for GHG funds in program year 2016 to 350 kgCO_2/MWh, with further reductions for subsequent program years to reflect increasing shares of renewable energy required in the future pursuant to § 399.15.

13. ~~12.~~ Under § 379.6(b)(2), it is reasonable for GHG-emitting technologies to demonstrate they will emit GHG emissions at a rate no higher than ~~360~~350 kgCO_2/MWh ~~during their~~averaged over the first ten years of operations, accounting for performance degradation, in order to receive ~~SGIP incentives.~~ GHG incentives. For technologies subject to the performance degradation assumption, the 350 kgCO_2/MWh ten-year average is equivalent to a first-year emissions rate of 334 kgCO_2/MWh.

14. ~~13.~~ It is reasonable for ~~SGIP~~GHG projects to continue to use an assumed boiler efficiency of 80%.

15. ~~14.~~ It is reasonable for ~~SGIP~~GHG projects to not include a separate marginal emission rate for exports from non-NEM projects.

16. ~~15.~~ ~~SGIP~~GHG should continue to use a peak line loss factor of 10.3% and off-peak line loss factor of 5.3% to determine the minimum round-trip efficiency for storage projects.

17. ~~16.~~ When calculating the minimum round trip efficiency for storage devices, ~~SGIP~~GHG should use the operating margin and build margin emission rates for CCGTs and CTs that are applied when calculating avoided emissions for generation projects.

18. ~~17.~~ Storage devices should demonstrate an average ~~an annual~~ round trip efficiency of at least 66.5% over ten years to qualify for ~~SGIP~~GHG under § 379.6(b)(2), which is equivalent to a first-year round trip efficiency of 69.6%.

ORDER

IT IS ORDERED that:

1. Within 30 days of the effective date of this decision, the Center for Sustainable Energy, Pacific Gas and Electric Company, Southern California Edison Company, and Southern California Gas Company shall jointly file a Tier 1 Advice Letter revising the Self-Generation Incentive Program Handbook, and related program documentation, to modify the greenhouse gas emissions standard ~~to 360 kilograms carbon dioxide per megawatt hour~~for program years 2016 through 2020 in conformance with the table in Appendix B to this decision

and to modify the minimum ~~average~~ round-trip efficiency for energy storage projects to 66.5% averaged over the first ten years of operations.

2. Rulemaking 12-11-005 remains open.

This order is effective today.

Dated ______________________________, at ~~Sacramento~~San Francisco, California.

Appendix A:

Share of Avoided Renewables in Calculating GHG GHG Emissions Eligibility Threshold

Assumed RPS Targets 2020 – 2030, with and without Line Loss Adjustments

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Nominal RPS	33.0%	34.8%	36.5%	38.3%	40.0%	41.7%	43.3%	45.0%	46.7%	48.3%	50.0%
Adjusted RPS	30.2%	31.8%	33.4%	35.0%	36.6%	38.2%	39.7%	41.2%	42.8%	44.2%	45.8%

Note: The adjusted RPS is calculated as the product of the nominal percentage and (1 – the line loss factor)

Average Share of Avoided Renewable Energy in Build Margin by Program Year

Program Year	2016	2017	2018	2019	2020
Build Margin RPS, Nominal	40.0%	41.7%	43.3%	45.0%	46.7%
Build Margin RPS, Adjusted for line losses	36.6%	38.2%	39.7%	41.2%	42.7%

Note: The build margin for each program year is the simple average of the RPS percentages for years 6 – 10 after the program year. For example, the program year 2016 average share of renewable energy avoided equals the average of the RPS targets for 2022 through 2026.

(End of Appendix A)

Appendix B:

GHG GHG Eligibility Emissions Factors, $kgCO_2/MWh$

Program Year	2016	2017	2018	2019	2020
10-Year Average	350	347	344	340	337
First-Year Average	334	332	329	325	321

(End of Appendix B)

Appendix ~~A~~C: Calculation of Minimum Round-Trip Efficiency

Line Loss On Peak	10.3%				
Line Loss Off Peak	5.3%				
Degradation Rate	1.0%				
First Year RTE	69.6%				
Ten -Year Avg RTE	66.5%				
Sum of Ann'l GHGs	0				

Year	Off-peak ER	On-peak ER	GHG emitted	GHG avoided	Net GHG per MWh
1	382	544	580	606	-27
2	382	544	585	606	-21
3	382	544	591	606	-15
4	382	544	597	606	-9
5	382	544	603	606	-3
6	368	524	587	584	3
7	368	524	593	584	9
8	368	524	599	584	15
9	368	524	605	584	21
10	368	524	611	584	27

(End of Appendix C)

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